Report EP 77-2

CA1 MS1
-77R02

Oil Sands and Heavy Oils: the prospects

3 1761 11767485 3

Energy, Mines and Resources Canada
Énergie, Mines et Ressources Canada

CA1 MS 1
-77R02 Government
Publications

Energy, Mines and Resources Canada
Énergie, Mines et Ressources Canada

OIL SANDS AND HEAVY OILS: the prospects

LIBRARY
MAY 10 1977
UNIVERSITY OF TORONTO

Report EP 77-2

© Minister of Supply and Services Canada 1977

Available by mail from

Printing and Publishing
Supply and Services Canada
Ottawa, Canada K1A 0S9

or through your bookseller.

Catalogue No. M23-12/77-2 Canada: $3.00 (2 vols.)
ISBN 0-660-00859-9 Other countries: $3.60 (2 vols.)

Price subject to change without notice.

FOREWORD

This document has been prepared as an interpretive companion report to the publication *Oil and Natural Gas Resources of Canada, 1976* prepared by the Department of Energy, Mines and Resources. The Department considers it important to inform the public of the prospects and also the problems associated with our largest known energy resources—oil sands and heavy oils. While the companion document represents, in effect, a snapshot of Canada's overall oil and gas resource endowment based on data available to year end 1975, the estimates and projections presented here represent judgements regarding future developments. In certain instances these judgements presume continuing evolution of technology, particularly in the area of surface recoverability of oil sands and heavy oil, along with continuing increases in Canadian oil prices and improvements in project economics.

In its April 1976 publication, *An Energy Strategy for Canada,* the Department indicated that despite the enormous potential for energy supply promised by our oil sands and heavy oil resources, an increasing shortfall in domestic crude oil supply would probably develop over the next fifteen years. A target was set of ensuring our net dependence on imported oil in 1985 would not exceed one third of total oil demand, thus implying greatly increased reliance upon oil sands and heavy oils in the absence of hoped-for major oil discoveries in our frontier areas. Thus, in the face of less encouraging forecasts of development of frontier resources, the Minister of Energy, Mines and Resources has stated the Department's intention to develop, in cooperation with provincial governments, policies that would foster increased exploitation and utilization of oil sands and heavy oils.

The implementation of such policies, however, depends heavily upon technological and economic factors. These resources differ from conventional oil and gas in that their existence, magnitude and character have been well known for decades; a sharp contrast to our conventional frontier oil and gas resources which are remote, whose magnitude and location are largely unknown and which will require enormous expenditures in terms of both time and financial resources merely to develop reliable estimates of deposit locations and quantities. While the oil sands and heavy oil resources of Alberta and Saskatchewan do not suffer from these uncertainties, their successful exploitation is not without risk. The technical problems of recovery from the reservoir together with the requirement that these bituminous, sulphurous and asphaltic crudes be upgraded to a form acceptable in the Canadian marketplace, coupled with the economic problem of performing these costly functions while maintaining competitive end product prices, present a formidable challenge. It is to the problems and prospects of this challenge that this document is addressed.

Digitized by the Internet Archive
in 2023 with funding from
University of Toronto

https://archive.org/details/31761117674853

CONTENTS

Illustrations

SUMMARY

Canada's oil sands and heavy oil resources located in Alberta and Saskatchewan (as shown in Figure 1) include some of the world's largest known deposits of petroleum hydrocarbons. They represent however, generally high cost energy sources, difficult to wrest from the earth and not readily marketable in volume without extensive upgrading or pre-refining. A summary of pertinent resource characteristics is shown in Table 1.

The Lloydminster-area heavy oils have been known and produced from conventional oil wells for decades although very low reservoir recovery efficiencies have been realized. High production costs, poor transportability, unsuitable refinery product yields and the resulting limited marketability of these crudes however have combined to restrict development. Currently emerging enhanced recovery technology could substantially increase percentage recoveries at what appear to be reasonable cost levels to the point where Lloydminster-area heavy oil could become one of our important near-term oil sources. Currently available refining (upgrading) technology may be employed to convert these oils to desirable feedstocks or fuel components. As indicated in Table 1, active development of these resources could commence by the early 1980's.

The Cold Lake area contains a huge reserve of oil similar to Lloydminster but even heavier in nature; no primary or unassisted recovery is available from this field. *In situ* recovery technology, generally employing thermal methods, is considered to be technically proven and approaching the stage where commercial-scale projects may be initiated. The lead time required for engineering, project definition and construction however will delay the availibility of significant volumes of oil production until the mid to late 1980's. These oils also require significant upgrading. Overall project economics are expected to be marginal under existing tax and royalty systems at current and foreseeable international oil prices.

The enormous oil-sand resources of the Athabasca, Peace River, Wabasca and Buffalo Head Hills deposits (referred to generally herein as Athabasca-type oil sands) contain bitumen that is generally solid unless heated. Some 10 per cent of these oil sands outcrops or is overlain by shallow depths of overburden and is considered to be mineable using open-pit techniques. The operating Great Canadian Oil Sands project and the Syncrude project under construction are typical of the use of mining methods. The remainder of these resources awaits the application of *in situ* recovery techniques currently under development. In either case, a significant amount of upgrading of the produced bitumen is required to make the resulting product transportable and marketable. Regardless of the recovery technology employed, however, Athabasca-type oil sands projects are expected to be only marginally economic at foreseeable international oil prices and under prototype agreements for the sharing of revenues with governments. Rapid expansion of oil sands production will probably occur

Figure 1. Oil sands and heavy oil deposits in Western Canada.

only after *in situ* techniques have been proven and found economically viable; possibly by the late 1980's or early 1990's.

A necessary precursor of significant development of any of these resources is the establishment of appropriate regulatory frameworks by governments at all levels within an economic environment that recognizes the need for entrepreneurial endeavours and rewards. Acceptable oil-sand economics will only be achieved if Canadian oil prices continue to rise toward international price levels and these latter prices, in the long run, do not decrease in real terms.

Table 1
SUMMARY OF OIL SANDS AND HEAVY OIL RESOURCE ESTIMATES AND CHARACTERISTICS

	Lloydminster-Area[1]			Cold Lake	Athabasca-Type[2]	
	Enhanced Recovery			*In situ*	*Mining*	*In situ*
	"High"[3] Probability	*"50/50"[4] Probability*	*"Low"[5] Probability*			
Crude oil (bitumen) in-place (billions of barrels)	10.3	12.0	18.8	165	74	715
Anticipated surface recovery[6] (per cent)		20 – 30		12 – 25	51	10 – 30
Recoverable oil (bitumen) (billions of barrels)		2.0 – 5.0		20 – 40	38	72 – 200
Upgrading shrinkage and fuel[7] (per cent)		10 – 25		20 – 35	0.30	30 – 50
Recoverable upgraded oil (billions of barrels)		1.5 – 4.5		15 – 30	27	40 – 140
Status of recovery technology		Threshold of pilot-to-commercial transition		Technically proven	Commercial operation	Early pilot stage
Current economic viability		Probably economic, market constrained		May be marginal at international price levels	Marginal at international price levels	Unknown
Anticipated timing of active development		Early 1980's		Mid to late 1980's	Ongoing	Late 1980's Early 1990's

[1] *Lloydminster-Area* includes resources contained within mapped area, Figure 2.
[2] *Athabasca-Type* as used herein refers to the bituminous oil sand deposits of Athabasca, Peace River, Buffalo Head Hills and Wabasca.
[3] Refers to the 90% probability-of-occurrence estimate prepared by the Geological Survey of Canada.
[4] Refers to the 50% probability-of-occurrence estimate prepared by the Geological Survey of Canada.
[5] Refers to the 10% probability-of-occurrence estimate prepared by the Geological Survey of Canada.
[6] Recoverable at the surface prior to upgrading shrinkage or fuel usage.
[7] Lower range of value refers to process loss only, while upper range includes probable usage as fuel in thermal recovery processes.

INTRODUCTION

The companion document *Oil and Natural Gas Resources of Canada, 1976* contains estimates of Canada's oil and gas resources including conventional oil and gas in Western Canada and in our far-flung frontier areas, as well as our non-conventional oil sands and heavy oil resources located in Alberta and Saskatchewan. The oil sands estimates contained in that document were provided to the Department of Energy, Mines and Resources by the Alberta Energy Resources Conservation Board. These include the enormous bituminous oil sands deposits at Athabasca, Peace River, Wabasca, and Buffalo Head Hills (for convenience referred to herein generally as the *Athabasca-type* oil sands) as well as the very heavy oil deposits at Cold Lake, all of which are located in the Province of Alberta. Estimates presented in that document of a smaller but nonetheless very large resource—the Lloydminster-type heavy oil deposits of Alberta and Saskatchewan—were prepared by the Geological Survey of Canada. In keeping with the geological nature of that document, however, the latter resources were treated in a fashion comparable to conventional crude oil; specifically, recovery of resources-in-place was based upon historic norms. In the case of light and medium crudes an average recovery factor of 35 per cent was assumed (i.e. for every 100 barrels of oil in the reservoir, 35 barrels would ultimately be recovered). For Lloydminster-type heavy oils, recovery factors in the range of 5-10 per cent were assumed, based mainly upon the efficiency of demonstrated recovery mechanisms. In an era of rapidly increasing oil prices and significant evolution of technology, such an approach provides little recognition of the future prospects for this energy resource.

The companion "Resources" document reflects, as accurately as possible, our current knowledge of the physical characteristics of Canada's oil sands and heavy oils resources; it does not provide an interpretation of this information or a perspective on the prospects that these enormous resources hold for the reduction or elimination of Canada's growing crude oil supply shortfall. While the resources-in-place, taken together, represent probably the largest single known accumulation of petroleum hydrocarbons in the world, they have as yet failed to fulfill their historic promise. Technological and economic constraints have combined to limit development. This document then, is intended to address these issues.

While the Athabasca-type bituminous oil sands, the Cold Lake heavy oil and the Lloydminster-type heavy oil are generically and geologically similar, there exists gradational but significant differences in the technological problems associated with their efficient and economic recovery. The Athabasca-type oil sands deposits consist of a dense, black, viscous bitumen containing relatively large amounts of combined sulphur, within a largely unconsolidated sand matrix; the remainder of the void spaces being filled with clay and water. These characteristics occurring at the surface or under shallow overburden give rise to the mineability of these deposits and have led to commercial-scale mining projects in the vicinity of Fort McMurray. The lack of fluid properties, however,

also gives rise to the inability to produce these resources through conventional wellbores and the need for large energy inputs for *in situ* recovery projects.

The Cold Lake deposits contain heavy oil somewhat more fluid in nature, not unlike the consistency of proverbial January molasses, within thick loosely consolidated sandstone beds. This property, together with the deposit depths, prohibits the use of mining techniques but makes the deposits increasingly amenable to thermal methods of *in situ* recovery.

The Lloydminster deposits contain crude oil of still lower viscosity, near the very heavy extreme of conventional crude oils. Some primary and waterflood-assisted recovery, typically in the range of 5 to 10 per cent of oil-in-place, is generally attainable from these deposits although artificial lift (pumping) is always required.

The technology for recovery of these energy resources, therefore, may differ for each type of deposit and, indeed, applications may differ considerably from lease to lease because of differing deposit characteristics. With each resource, however, the problem of "getting the oil out of the ground" is one of major proportions for which the technology is currently in an evolutionary state. Each resource, in addition, shares in common the problems associated with refining and upgrading these asphaltic, sulphurous raw materials and the economic uncertainties associated with their effective utilization in Canadian energy markets.

In the following sections, each of the above groupings of the resource is discussed in terms of its general characteristics, estimates of oil-in-place, the technology of recovery and the prospects for the same. The utilization and marketing of heavy oils are then considered, along with economic questions. Finally, government initiatives undertaken to foster increased exploitation of these resources are discussed.

LLOYDMINSTER-TYPE HEAVY OILS

General Description

The Cretaceous heavy oil belt straddles the Alberta-Saskatchewan boundary from about Townships 32 to 55. The town of Lloydminster lies in the north-central part of the area (Figure 2). The outline shown on the map shows the approximate limit of heavy oil sands believed to be subject to some degree of primary recovery. For the purposes of this report, the heavy-oil resources contained within this outlined area are referred to as Lloydminster-type heavy oil.

Heavy oil in the conventional fields of the Lloydminster area occurs largely in the upper part of the Mannville Group. The individual sands starting at the top are the Colony, McLaren, Waseca, Sparky, General Petroleum, Rex, Lloydminster, Cummings and Dina. Within any part of the area usually one or two of the sands hold the bulk of the reserves. All of the sands may contain some oil within the region although most current production is from the Sparky and General Petroleum sands and to a lesser extent the McLaren, Waseca and Lloydminster sands. The sands where productive, are very fine grained, clean and relatively unconsolidated and grade laterally into siltstones or shale. Porosity generally exceeds 30 per cent. Oil saturation is high, commonly reaching 2 300 barrels per acre-foot and oil gravities can vary widely from 12 to 23° API with an equally large range of crude oil viscosities. Reservoir sandstones are generally 10 to 20 feet thick and occur at depths between 1 000 and 3 000 feet.

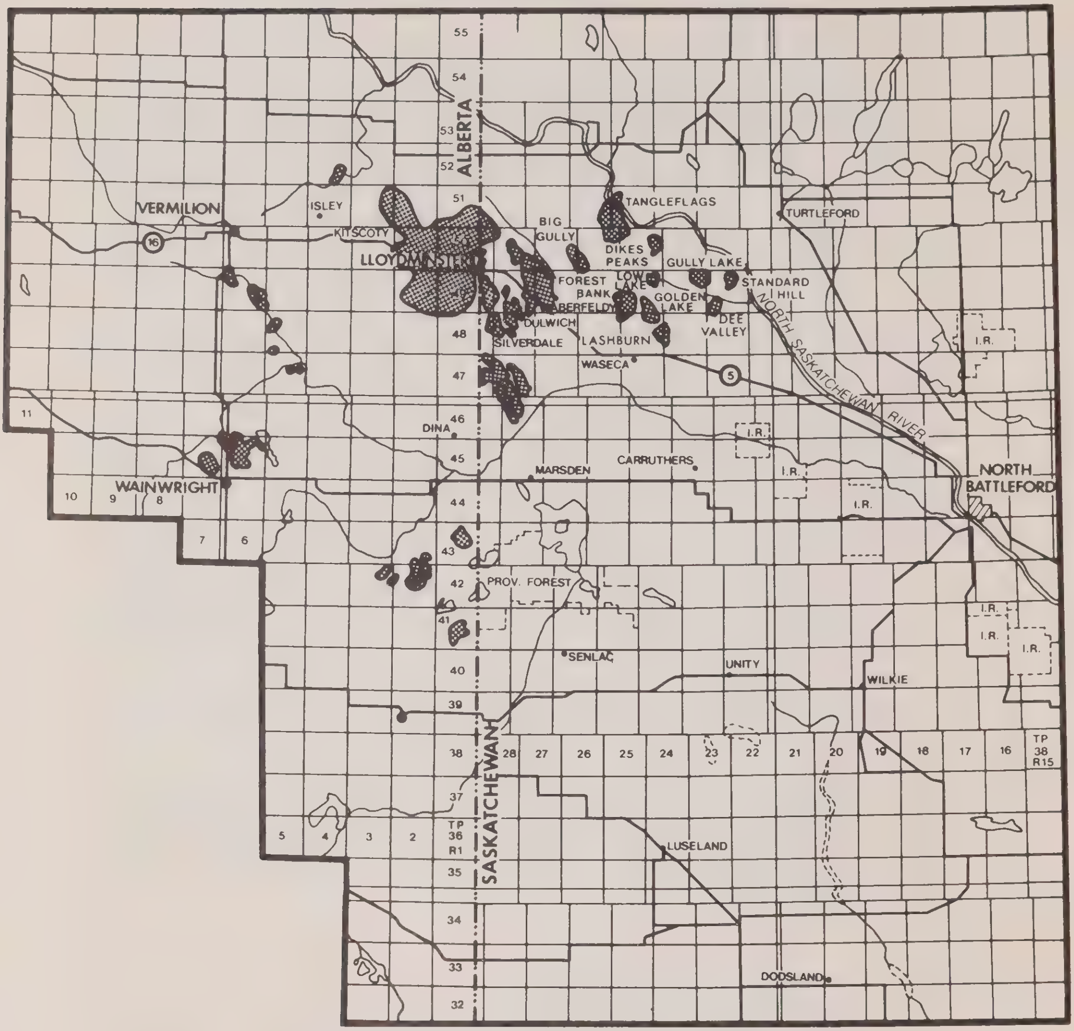
Provincial authorities have estimated that this area contains proven reserves of some 4 billion barrels of heavy oil-in-place. To date, some 160 million barrels have been produced; recent production rates have averaged in the range of 40 000 to 50 000 barrels per day.

Estimates of Resources In-Place

The recently completed assessment of Lloydminster-area heavy oil resources prepared by the Geological Survey of Canada is shown in Figure 3. This work was conducted in conjunction with the normal assessment of Western Canada oil and gas resources and indicates a significantly large and possibly a very large heavy oil resource in-place within the area outlined in Figure 2.

The results are based upon a sampling of well-control information considered to be representative of wells in the area rather than a detailed well-by-well analysis of drilling results for the large number of holes that have been drilled. Estimates were prepared and are expressed in Figure 3 in terms of cumulative probability distributions in accordance with the Geological Survey of Canada's methodology described in detail in *Oil and Natural Gas Resources of Canada, 1976.*

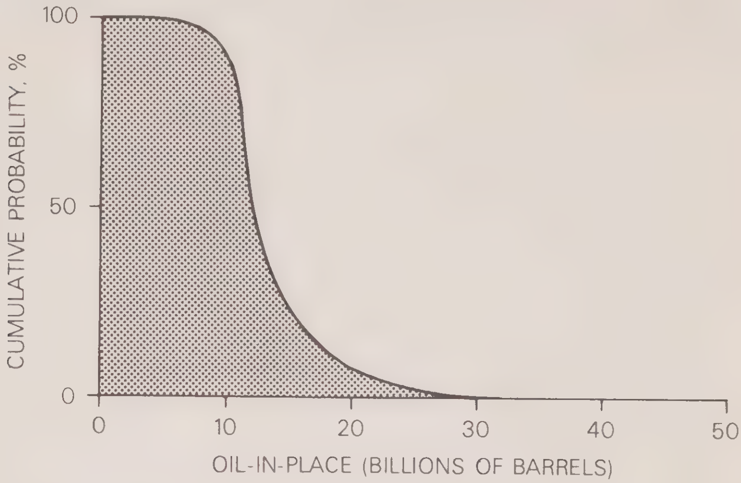
Figure 2. Lloydminster heavy oils assessment area.



While the study is continuing; and further refinements in the area, like all estimates of resource potential, will undoubtedly be forthcoming in the future, the following numbers taken from Figure 3 express the Geological Survey's current estimate of in-place resources.

Per cent Probability	*Crude Oil In-Place (billions of barrels)*
90	10.3
50	12.0
10	18.7

Figure 3. Lloydminster-area* heavy oils.



PROBABILITY	100	90	80	70	60	50	40	30	20	10	0
OIL-IN-PLACE	6 0	10.3	10.8	11.2	11.6	12.0	12 7	14.1	15 5	18.7	32 0

*See Figure 2 for outline of Lloydminster area considered.

It is significant to note at the 100-per-cent probability level the Geological Survey indicates a proven in-place reserve totalling 6.0 billion barrels recognizing resources not currently producing and not carried as reserves.

Lloydminster-area heavy oils do not represent a normal oil production situation and the percentage of oil-in-place that may be recovered may bear little relationship to conventional oil recovery efficiency. While historically, the percentage recovery of these heavy oils has averaged less than 10 per cent, tertiary recovery methods currently under development could increase these recovery factors substantially. For this reason, recovery technology and production economics must be analyzed in some detail.

Recovery Technology

Primary Recovery

Primary production in the Lloydminster area is principally by solution-gas drive. Recoveries are very low, averaging only 4 to 6 per cent of the oil-in-place due to the small amounts of solution gas available (about 50 cubic feet per barrel) and the viscous nature of the oil. The high viscosity of the oil and the unconsolidated nature of the formation cause high rates of sand production which have always been a major problem in the Lloydminster area. Different sand-control methods, such as the use of gravel packs, sand consolidation and

screens have all been tried without much success. It appears that attempts to control sand production also limits entry of fluid into the producing wellbore.

Waterflooding (Secondary Recovery)

Adverse mobility ratios for the heavy Lloydminster-type oils make waterflooding an inefficient process usually resulting in total primary and secondary recoveries of 8 to 10 per cent of the oil-in-place. In spite of the small incremental recovery over primary production, waterflooding is usually economic in that the produced formation water has to be disposed of in any event. Its return to the formation along with additional make-up water can be achieved at a relatively low incremental cost. This process, however, has not proved to be economic in primary depleted reservoirs i.e., reservoirs that have been depleted of their primary, solution-gas energies. As primary depletion progresses, the oil viscosity increases as gas in solution is lost, resulting in an adverse effect on the mobility ratio between the water and oil. As well, the gas coming out of solution causes some areas in the reservoir to increase in free gas saturation. These areas are then more susceptible to water channelling from the injection well to producing wells. This tendency to channel is of course strongly affected by the state of depletion of the reservoir when waterflooding is initiated.

Tertiary (Enhanced Recovery)

The most appropriate technology for tertiary recovery of the relatively low temperature Lloydminster crudes at the present time involves the use of thermal methods. These general techniques are applicable.

Steam: Steam basically serves to increase the temperature of the heavy oil, thereby reducing its viscosity and facilitating migration towards the wellbore. Condensed water in the formation helps maintain reservoir pressure. Generally a steam "soak" period of perhaps 30 days is initiated, followed by a brief shut-in period to enable some temperature stabilization to occur in the formation, after which the well is produced for several months. This procedure is also known as "huff and puff" and generally precedes a patterned "steam drive" operation in which steam is injected down certain wells with production occurring at other wells.

Steam operations generally require more expensive piping networks to handle the higher-temperature, more corrosive steam and produced liquids. Casing is usually heavier and higher-temperature cement is generally employed. These, however, are engineering problems that are solvable.

A factor that decreases the effectiveness of steam operations in the Lloydminster area is the relative thinness of the sand lenses (10 to 20 feet). Heat losses to the formations above and below the oil-bearing formation are appreciable when the sands are thin. Other things being equal, a thicker sand absorbs a higher proportion of the injected heat than a thinner sand, assuming the steam may be conveyed more or less uniformly. Cost per Btu placed in the oil-bearing

zone is therefore lower, resulting in better project economics. For this reason steam projects are preferred in the Cold Lake region where pay thicknesses of 50 to 100 feet and more are common. Steam economics are also assisted by shallower formation depths which reduce the heat loss around the wellbore during injection.

Fireflood (forward combustion): This technique basically involves the continuous injection of air into injection wells to help propagate a burning front through the formation. As the combustion zone moves through the formation, interstitial water, the water of combustion, and a portion of the oil are vaporized. These vaporized fluids move ahead of the combustion zone where they condense. The condensed fluids and the imposed gas drive displace fluids ahead of them. Oil which is not displaced or vaporized is modified to a coke-like material by the high temperature existing at the leading edge of the combustion zone. The coke-like material is the fuel that remains to be burned. As the combustion zone moves ahead, with temperatures above 800° F, all of the fuel is consumed leaving a burned-out region void of oil and water.

Wet Combustion: This method, which has been tried by most heavy-oil producers, is a modification of the forward combustion process with the variation that water is injected with the air. The injection of water significantly increases the heat-transport capacity of the fluids passing through the burned-out region. This results in cooling of the burned-out region and transporting of the scavanged heat downstream ahead of the combustion front where it can heat the reservoir oil and aid in its displacement. The injection of water also quenches the trailing edge of the combustion zone before all of the fuel is consumed, thereby enabling a more rapid movement of the combustion zone through the reservoir.

Combustion methods do not require expensive chemicals as do some enhanced recovery methods. The primary input materials are air and water. The most significant single cost factor is air-compression equipment.

Pilot Thermal Recovery Projects

A number of thermal projects have been initiated in the Lloydminster region ranging from single wells to large-scale integrated schemes. The following are brief descriptions of some of the larger projects.

Murphy Oil Ltd. has a wet-combustion operation in the *Silverdale* field approximately 10 miles south of Lloydminster on the Saskatchewan side. The project has been in operation for three years and to date has produced an additional 7.3 per cent of an estimated 1 440 000 barrels of 14.5° API gravity oil-in-place. Primary recovery was 9 per cent (with fewer wells) and Murphy expects to recover an additional 21 per cent for a total recovery of 30 per cent. (Model studies on this project resulted in an estimated ultimate recovery of approximately 50 per cent).

The pool is in the Sparky formation at a depth of 1 800 feet. Pay thickness is only 12 feet and permeability in the unconsolidated sand is very high. The development pattern is essentially an inverted nine-spot on a forty-acre plot.

General Crude Oil Company Northern Ltd., a relative newcomer to Canada but not to world heavy-oil operations, currently has two projects underway in Alberta, although neither has as yet been ignited: a one-and-a-half-section (960 acres) operation initially involving about 95 wells at *Kitscoty*, and a one-section (640 acres) operation at *Silverdale* involving 52 wells. Additional wells will be drilled at infill locations later when a decision is made to change the production pattern.

The sands in both projects are about 15 feet thick at a depth of 1 800 feet. Reserves in place at the *Kitscoty* project are estimated at 31 150 000 barrels of 14° API crude, of which 7 000 000 barrels are expected to be recovered (22 per cent) at a rate of 2 000 barrels per day. General Crude took over the *Kitscoty* property after it had been depleted on primary production by another operator who achieved 3-per-cent recovery. The *Silverdale* project is currently producing 1 200 barrels per day on primary (16° API) and is expected to reach 1 800 barrels per day on fireflood. Oil-in-place is estimated at 19 600 000 barrels of which 6 300 000 barrels or 31 per cent is expected to be recovered.

Husky Oil Ltd. is the principal landholder in the area and is currently operating two wet-combustion fireflood projects in Saskatchewan. It has also experimented with steam, commencing with a project at *North Dulwich* in 1965, and is currently considering another steam pilot in Saskatchewan.

A fireflood project located at *Golden Lake South* appears to be marginally economic under present conditions. In that pilot project, an inverted five-spot pattern was ignited in 1969, followed by two adjoining inverted seven-spot patterns in 1974. Pay thickness in the Sparky sand is from 20 to 23 feet at a depth of 1 600 feet. Currently, two wells in the original five-spot pattern have sanded up and are no longer operated. The remaining two and the ten production wells in the seven-spot patterns are producing 380 barrels per day (30 barrels per well). Ultimate recovery of as high as 35 per cent of the estimated 3 800 000 barrels of oil-in-place within the pattern areas may be possible, although this figure is hypothetical at this time.

A larger project (43 producers, 7 injectors) at *Aberfeldy* is apparently uneconomic under current conditions. This is attributed to a thinner (15-foot) and less homogeneous pay zone. Ultimate recovery of the estimated 22 500 000 barrels in-place may range as high as 25 per cent.

For most of these projects, investment per unit of production has averaged in the range of $4 000 to $6 000 per daily barrel of new production capability. The costs of possible future commercial-scale projects, however, can only be inferred from these historic costs. Full-scale projects generally will benefit from economies of scale but increasing real costs over time and the need for more

sophisticated and automated equipment and operations will tend to increase real costs.

Recoverable Oil—A Projection

Pilot recovery project results indicate that recoveries ranging up to 50 per cent of oil-in-place may be theoretically and physically possible. Commercial projects under comparable conditions in the heavy oil belt of Southern California and in Texas have sometimes exceeded this figure. While no two oilfields are the same, there is every reason to believe that at least some Lloydminster-type oilfields can achieve such recovery factors. Certain pilot projects, and possibly even commercial-scale projects, will fail; recoveries may not be materially enhanced by costly tertiary recovery methods. This is, of course, a risk that will have to be faced. Such risks can and must be minimized by improved technology generated through theoretical and pilot-scale research; by improved knowledge of reservoir and fluid characteristics; and by the assurance of long-term, continuous market outlets which will allow uninterrupted project operation from initiation through to abandonment. Many successful projects will encounter technical problems and will not achieve hoped-for recoveries. Given the very low level of primary recovery however, an enhanced recovery of 20 per cent or higher will probably be regarded as at least a technical success.

The technical risks of these enhanced recovery projects, particularly beyond the pilot project stage, will be borne primarily by the private-sector oil companies. The technological and human resources are resident with Canada's oil industry. Adequate exploitation of these energy sources however can only be achieved within an appropriate environment of government regulation and incentive which will foster risk-taking and research and development on a scale necessary to achieve efficient utilization of this resource.

Within such a framework, pilot and commercial-scale endeavours should blossom. Cross fertilization and learning curve effects will, it is hoped, lessen the incidence of failure and improve recovery factors, generally. At the current rate of development of technology, prediction of ultimate recovery factors averaging 20 to 30 per cent of oil-in-place for the entire Lloydminster-area resource appears technically feasible. Such a prediction implies ultimate recovery ranging from 2 billion barrels (i.e. 20 per cent of 10 billion barrels in-place; the 90-per-cent geological probability decile) to as much as 5 billion barrels (i.e. 30 per cent of 18.7 billion barrels in-place; the 10-per-cent probability decile). Such admittedly subjective assessments depend heavily upon as yet undiscovered resources or geologic potential. Low recovery factors applied to the 100-per-cent decile, i.e. the current proven reserves, for example, would result in a minimum estimate in the order of 1 billion barrels of recoverable oil. At the other extreme, ultimate recovery in the range of 5 billion barrels would require the application of tertiary recovery methods to even the smaller fields, combined with the fortuitous geological occurrence of resources. Needless to say, such ultimate

recoveries would require strong incentives in the area of economics along with continued favourable development of technology. While ultimate recoveries may therefore range from 1 to 5 billion barrels, or possibly more, effective development of this potential may require a minimum of a decade or longer to achieve and can certainly only take place in the presence of strong financial incentives and with access to adequate markets.

Production rates from individual heavy-oil pools during peak production periods could average one barrel per day for each 5 000 barrels of recoverable reserves. Obviously, all pools cannot achieve peak production simultaneously; development will take place over a decade or two. Recognizing this principle, average production rates could be in the range of 100 000 barrels per day per billion barrels of recoverable oil. The range of estimates of recoverable oil could therefore give rise to ultimate total production from Lloydminster-type heavy-oil tertiary recovery projects ranging from 100 000 barrels per day to as much as 300 000 barrels per day or more. As mentioned, such development may take a decade or longer to achieve, will depend heavily upon the continued successful development and application of tertiary recovery methods and will require the establishment of an economic environment receptive to enhanced recovery projects. The development of appropriate and assured market outlets is, of course, an essential part of such an environment.

The limited and seasonal nature of market outlets for this oil has historically been the major factor restraining development of production potential at Lloydminster. While this oil is a preferred feedstock for asphalt manufacture, this market is highly seasonal in nature and limited to those refiners possessing the specialized equipment necessary to handle heavy oil. Large-volume sales have been dependent upon the export market, particularly to "northern tier" refiners in the United States, many of which have installed special equipment to process heavy Canadian crude. The NEB's recent decision to grant separate export licenses for Lloydminster-type heavy oils, separately from light and medium crude exports which are restricted, therefore constitutes an important step in developing the production potential of the area. Long-term (i.e. at least 5 years) assurance of the continuing availability of these markets should stimulate a considerable drilling program. Nonetheless the upper limit in production and marketability, under present marketing procedures, is determined primarily by the asphalt market and by refiners' capabilities to handle heavy oil. Such will be the case until a heavy-oil upgrading facility is built, probably in Alberta or Saskatchewan, to upgrade these oils into fuel components, i.e. energy commodities, more suitable to Canadian market requirements. Several companies are actively studying the construction of such a facility. Although planning is still in the formulation stage, it is anticipated that an announcement of a firm project plan could soon be forthcoming.

The combination of factors described above—substantial production potential, a relatively well known resource base and probable acceptable production economics—make Lloydminster-type heavy oils possibly Canada's best hope for near-term additions to the supply of liquid hydrocarbon fuels.

COLD LAKE DEPOSITS

General Description

The Cold Lake oil-sand deposits underlie an area of approximately 3 500 square miles in eastern Alberta (Figure 1). They are covered by 900 to 1 600 feet of overburden consisting mainly of Cretaceous strata. The 10 to 14° API gravity bitumen has been trapped in the sands of the Mannville Group by stratigraphic pinchout and structural conditions. This layered sequence of sand lenses with varying degrees of bitumen saturation is divided into three separate deposits in stratigraphic units that comprise the entire Mannville section. These deposits are in descending order, the Cold Lake "A" (occurring in the Upper and Lower Grand Rapids Members), the Cold Lake "B" (occurring in the Clearwater Formation) and the Cold Lake "C" (occurring in the McMurray Formation). It is not yet possible to determine the northern limits of deposits in the Clearwater and Lower Grand Rapids units as drilling has been restricted in that area due to the presence of the Primrose Lake Air Weapons range. Recent drilling along the Saskatchewan border on the eastern flank of the field however has failed to extend the limits of the field onto the Saskatchewan side.

Estimates of Resources in-Place

As described in the companion document *Oil and Natural Gas Resources of Canada, 1976*, the Alberta Energy Resources Conservation Board estimated a total of 165 billion barrels of bitumen-in-place in the three Cold Lake zones listed below.

Deposit	*Areal Extent* (thousand acres)	*Average Pay Thickness* (feet)	*Initial In Place* (Bstb)
Cold Lake A	1 800	53	118
Cold Lake B	650	40	33
Cold Lake C	710	16	14
			165

These values were determined by examining wells in the area and deriving pay values for each hole, mapping and isopaching the values and measuring the reserve volume. Based on average values of porosity and bitumen saturation, bitumen-in-place is approximately 1 200 barrels per acre-foot. A square mile underlain by 50 feet of oil sand therefore probably contains almost 40 million barrels of bitumen-in-place. The best areas of the field contain sands of 100 feet or more in thickness.

Recovery Technology

The technology that is indicated for the recovery of Cold Lake heavy oil at this time involves thermal stimulation by steam injection to lower the viscosity of the deposit bitumen. Several operators are experimenting with steam-injection pilots and may ultimately convert to patterned steam drive. (Steam-recovery techniques are described in the Lloydminster section of this report.)

Imperial Oil Limited is the largest landholder and has been doing active experimental work for ten years. The *Leming* pilot is a case in point where expenditures have totalled $15 million since 1973. This project consists of eight pads of seven wells, with the centre well in each cluster drilled vertically and the other six drilled directionally to provide 600 horizontal foot spacing in a 160-foot-thick section of the Clearwater Formation at about 1 400 feet of depth. The pilot is centred on plant facilities which include water-treating and steam generation, separators and treaters for crude oil processing and oil-storage and loading facilities. Current production is approximately 5 000 barrels per day.

The wells are steamed for about a month and initially flow to the surface for about a week, after which they are pumped for several months. The produced oil, gas and water is piped to the central separators where the gas is taken off for use as a fuel or for re-injection. The produced water is returned to a deep formation and the oil is trucked to market.

Murphy Oil Company Ltd. has been operating a project at *Lindbergh* since 1974 and ultimately plans a conversion to full steam drive. Production is some fifty barrels per day. Union Texas of Canada, Ltd. is currently producing 220 barrels per day from a pilot near *Ardmore*. Several other companies are also active, with Norcen Energy Resources Limited currently preparing to produce an expected 500 barrels per day from 12 wells near *Primrose Lake*. Chevron Canada Ltd. has a one-well pilot at *Beaver Crossing* and Weco Development Corporation is producing 70 barrels per day from one well near *Fort Kent*. B.P. Canada Limited operated two pilots at *Marguerite Lake* between 1965 and 1970 and is currently preparing for another pilot capable of 500 to 1 000 barrels of oil per day in conjunction with the Alberta Oil Sands and Technology Research Authority. Gulf Oil Canada Ltd. is also planning a 12-well pilot commencing in 1977. By far the most significant operator at this time and likely the first candidate for conversion to commercial operations is Imperial Oil. A lead time of approximately ten years is indicated for planning and construction of a full-scale operation expected to produce in the order of 100 000 barrels per day.

An EMR study indicates that a 100 000-barrel-per-day *in situ* scheme with an expected life of 25 years would cost in the neighbourhood of $2.6 billion to $3.0 billion (1976). Initial investment over the first five years, of between $1.6 billion and $1.8 billion, would be required about as follows:

Table 2

CONCEPTUAL COSTS—COLD LAKE *IN SITU* RECOVERY PROJECT
(100 000 barrels per day of upgraded crude)

	Capital Cost (1976 constant dollars —millions)
Upgrading facilities	400 600
Steam and power plant	400
Steam distribution, production gathering	300
Wells (initial requirements about 3 000 wells)	500
Total—initial	1 600–1 800

After the fifth year additional wells would be required every year at a cost of between $50 million and $60 million per year. Initial well-spacing would be 5 acres per well, filling in to approximately 2.5 acres per well at maturity. Initial production would be 50 barrels/day per well.

Operating costs of $150 million to $200 million per year could be incurred with a payroll of between 300 and 400 individuals in the production end, some 800 in the upgrading facility, and administration and management staff of perhaps 600. Total ongoing employment of 1 800 individuals could be required.

The above estimates imply total capital and operating costs only (i.e. the physical cost) totalling $7 to $9 per barrel of synthetic or reconstituted crude oil recovered, processed and marketed. These figures exclude interest expense, return on investment, taxes and royalties. The very high cost nature of this technology is thus evident. The physical cost of *in situ* recovery projects at Cold Lake would appear to be similar to oil sands mining costs for the Syncrude project.

Recoverable Oil—An Estimate

The volume of heavy oil-in-place at Cold Lake is huge, some four times as large as all conventional oil (in-place) resources discovered in Canada to date. Yet while conventional oils can anticipate a recovery factor of 35 per cent or higher, Cold Lake remains virtually untapped. Future recovery will depend upon a favourable combination of developing technology, an acceptable economic environment and a government policy framework that provides incentives for development. Even under such far-reaching assumptions, a broad range of ultimate recovery estimates is possible.

The Alberta Energy Resources Conservation Board (AERCB) suggests an ultimate recovery potential for oil sands generally of 33 per cent including Cold Lake. Private companies are predicting 50 per cent and better for specific pilots. A reasonable recovery range for those Cold Lake deposits amenable to *in situ*

recovery at this stage of development of technology could therefore be from 25 to 50 per cent of the bitumen-in-place. Assuming that economics and deposit characteristics are such that about one half of the deposits will actually be amenable to exploitation would imply a bitumen recovery range between 20 and 40 billion barrels (12 to 25 per cent of total bitumen-in-place). This estimate is considerably more conservative than, for example, the AERCB's view which, however, relates to an "ultimate" recovery. In light of the uncertainties that still exist regarding the deposits themselves, the current status of *in situ* recovery technology, future economic and institutional parameters and the very long lead times that will be required to achieve efficient levels of exploitation, it is considered to be a reasonable target at this time. In fact, theoretical arguments regarding the ultimate recovery factor are quite meaningless; production volumes and timing remain as the critical variables from the point of view of both Canadian consumers and government policy makers.

The upgrading process for Cold Lake heavy oil is likely to be quite similar to the upgrading of the 6 to 10° API Athabasca deposits where a factor of 0.70 is being realized in converting surface bitumen to synthetic crude oil. Employing a surface conversion factor of 0.70, therefore, the ultimate recovery range expressed in terms of synthetic crude is estimated to be in the range of 15 to 30 billion barrels.

It seems likely that within about a decade this resource will begin to have an impact upon the Canadian oil-supply situation.

ATHABASCA, PEACE RIVER, WABASCA AND BUFFALO HEAD HILLS DEPOSITS

General Description

These deposits are spread over a large area of northern Alberta as indicated in Figure 1. The Athabasca deposit occurs within the McMurray Formation and the overlying Wabiskaw sandstone member of the Clearwater Formation. Thicknesses of these deposits may exceed 200 feet, with variations being related to the relief of an underlying Paleozoic surface. Areas where the Wabiskaw-McMurray unit is abnormally thick correspond to areas of low relief on the Paleozoic surface, and conversely. Gravities of the in-place bitumen generally range between 6 and 10° API.

The crude bitumen reserves of the Peace River area occur in the Bluesky and Gething Formations of Lower Cretaceous age. These formations comprise a clastic sequence lying unconformably on subcropping strata of Jurassic, Permian and Mississippian ages. The sequence pinches out against Mississippian carbonates to the northeast, with the Bluesky sediments onlapping those of the Gething Formation. Depth of burial ranges from 1 500 to 2 600 feet.

The Wabasca A deposit occurs in the Grand Rapids Formation of Lower Cretaceous age. The Wabasca B deposit occurs in the Wabiskaw unit, similar to the Athabasca deposit. Overburden thicknesses vary from 300 to 1 100 feet, generally thickening in a southward direction.

Estimates of Resources in-Place (AERCB)

As shown in the companion document *Oil and Natural Gas Resources of Canada, 1976* the reserves of bitumen-in-place as estimated by the Alberta Energy Resources Conservation Board are as follows:

Table 3

CRUDE BITUMEN RESERVES

Deposit	*Areal Extent* (*thousand acres*)	*Average Pay Thickness* (*feet*)	*Initial In Place* (*billions of barrels*)
Athabasca			
Mineable	490	100	74
In situ	5 260	70	553
Buffalo Head Hills	159	7	1
Peace River	1 606	45	75
Wabasca A	1 342	25	48
Wabasca B	1 721	20	38
			789

A significant part of the Athabasca deposit is overlain by 150 feet or less of overburden and is considered to be accessible using surface mining techniques. By far the largest part of the Athabasca deposit and all other deposits however, are expected to be recoverable only by *in situ* methods.

Recovery Technology

Surface Mining Operations

Parts of the Athabasca oil sands are the only deposits amenable to surface mining techniques at this time. Under current circumstances overburden thicknesses in excess of 150 feet (depending upon grade and sand thickness) generally preclude surface mining operations.

The oil-bearing material in the Athabasca region is a mixture of sand, water and bitumen with some clay. The predominant sand component is quartz in the form of rounded or subangular particles. A film of water wets the sand grains and the wetted particles are covered by a film of bitumen that partially fills the void volume. Water fills the rest of the voidage, along with occasional small volumes of gas (usually air, but occasionally methane). The sand grains are packed to a void volume of about 35 per cent corresponding to a mixture of approximately 85-to-90-weight-per-cent sand and 10-to-15-weight-per-cent bitumen with water. The presence of significant but erratic amounts of clay throughout the deposit makes any type of recovery operation difficult.

The basic physical tasks necessary to bring a surface mining project to fruition are as follows:

1. Overburden removal
   — tree clearing
   — overburden drainage
   — stream diversions
   — muskeg removal
   — dyke construction
   — overburden stripping
2. Excavation or mining of the oil sand
3. Transportation of the oil sand to the extraction plant
4. Extraction of bitumen
5. Bitumen upgrading to synthetic crude
6. Tailings handling
7. Land reclamation

To date, one project, Great Canadian Oil Sands (GCOS), is operational; a second, the Syncrude project, is under construction; while at least three other proposals have reached at least the planning stage but appear to be shelved for the time being.

The GCOS plant went on stream in 1967 and immediately experienced a variety of unforeseen or only partially foreseen difficulties despite the comparatively high quality of its lease. These problems have in part been overcome so that the project is continuing to improve its operating efficiency. Following overburden removal by conventional earth-moving equipment, two large bucket-wheel excavators are used to mine the bitumen. Conveyors carry the oil sand to the extraction plant where a hot-water process separates the bitumen from the sand. The bitumen is subsequently further purified and introduced into a coking facility at around 900° F where the bitumen is physically broken into lighter materials and heavier coke. The latter material contains most of the sulphur and other impurities. The distillate (overhead from the coker) is desulphurized and after further desulphurization the lighter streams are then pipelined to Edmonton.

The Syncrude project is currently under construction on a 50 000-acre lease adjoining that of GCOS. Currently planned capacity is 125 000 barrels per day compared to the current capability of 50 000 barrels per day for GCOS. Bitumen reserves are sufficient to support capacity operation for at least 25 years. Large walking draglines will be used to remove overburden and mine the deposits. Oil sand will be stockpiled on the surface for subsequent loading onto conveyors by bucket-wheel reclaimers assisted by front-end loaders. The bitumen-sand separation process is basically the same as for GCOS. A modification in the upgrading process at the coking stage will substantially reduce the large volumes of sour coke that would otherwise be produced.

Shell Canada Ltd. has received AERCB approval for a 100 000-barrel-per-day plant on a lease containing about 50 000 acres, of which 13 000 are deemed mineable a few miles north of Fort McMurray. At capacity throughput sufficient reserves exist for 67 years of production, implying substantial potential for expansion in the future. A mining and separation procedure similar to Syncrude is proposed, however upgrading would employ vacuum distillation, solvent deasphalting and hydrocracking of the bottoms product rather than coking. This particular project has been shelved indefinitely.

The other two project proposals, Petrofina *et al*, and Home-Alminex, both involve bucket-wheel excavators and conveyors, hot-water separation and coking. They will not be documented further because of uncertainty regarding corporate plans for further involvement.

In Situ Operations

Thus far, no commercial-scale proposals have been advanced applying *in situ* methods to Athabasca-type bituminous sands deposits. However as the vast bulk of the oil-sands deposits appear to be accessible only through *in situ* methods, there is an obvious need to upgrade our knowledge of this technology. Towards this end, the Alberta Oil Sands Technology and Research Authority (AOSTRA), funded by the Alberta Government, has allocated $64 million to

five experimental projects: Shell Canada Ltd. (Peace River), Amoco Canada Petroleum Company Ltd. (Athabasca), B.P. Exploration Canada Limited (Cold Lake), Numac Oil and Gas Ltd. (Athabasca) and In Situ Research and Engineering Ltd. (basic research), in the hope of developing new or improving existing recovery methods. (Additional funding has been authorized by the Government of Alberta bringing the total to $144 million under the AOSTRA program.) The indicated technology at this time appears to involve thermal methods similar to those described for the Lloydminster and Cold Lake deposits.

A number of companies have been active in *in situ* recovery research during the last two decades. Amoco Petroleum Canada Limited has undertaken a series of pilot tests leading up to its current project (in conjunction with AOSTRA), involving a total of 37 production, injection and observation wells employing a modified *in situ* combustion process. Shell Canada Limited was active during the period 1957-62, primarily in the area of steam stimulation in the Athabasca area but is now concentrating its efforts on the Peace River deposits. A considerable area of the oil-sands deposits are covered by between 200 and 500 feet of overburden, which is too great for surface mining operations but does not offer sufficient pressure to sustain a regular steam operation. Petrofina addressed this problem on behalf of a group of companies with a pilot operated between 1966 and 1969, and Texaco is presently operating a 52-well pilot at a depth of 250 feet that has produced in excess of 50 000 barrels. Similarly, Gulf Canada Limited is currently experimenting with a small pilot at Wabasca. There appears to be little momentum evident at this time, however, for scaling up to a commercial-size project.

Underground Mining

The feasibility of employing modified underground mining techniques is receiving increasing attention. The Soviet thermal mining method which employs a combination of thermal methods with subsurface excavation is operational in at least one project in the USSR and may be applicable to the Alberta oil sands. The method combines the desirable environmental aspects of *in situ* techniques with the possibility for high recovery efficiencies of mining methods. The high bitumen viscosities and high sulphur content of our oil sands would however increase project costs and possibly result in unacceptably hazardous operations. The technique appears to be sufficiently promising to warrant further technical and economic study.

Other underground mining methods are continually being brought forward or are being studied. Because of the magnitude of the resource, and thus the rewards involved, this trend is likely to continue. Hopefully it may result in the generation of new ideas or improvements in efficiency which will eventually lower the cost of oil-sands operations.

Recoverable Oil—An Estimate

In the companion document *Oil and Natural Gas Resources of Canada, 1976*, some 38 billion barrels of raw bitumen or 26.5 billion barrels of synthetic crude is forecast by the AERCB as being recoverable from the mineable portion of the oil sands. As mentioned previously however, the AERCB has projected a potential ultimate recovery factor of 33 per cent of bitumen-in-place employing both *in situ* and mining methods. This would result in some 25-per-cent recovery of synthetic oil after upgrading. Also as discussed previously, these resources are so large that arguments regarding ultimate recovery factors are not particularly useful; the timing and production rates of future oil supplies from oil-sands sources are far more relevant considerations. Nonetheless a very brief discussion of recovery factors is warranted.

The term "recovery factor" must be interpreted with some care as it is sometimes used in different contexts. The first relates to the ratio or percentage of bitumen-in-place recoverable at the surface, i.e. the surface recovery factor. The second applies to the proportion of synthetic crude oil remaining of the original bitumen feedstock to the upgrading plant after deducting process losses and sometimes fuel, i.e. the process recovery factor. In a mining operation the recovery of bitumen from bitumen-in-place will be high, limited only by marginal thicknesses, inaccessible areas and similar factors. The synthetic crude that may be derived from the bitumen will be a function of its raw composition, the type of process employed, as well as the possible utilization of outside fuel sources. Based on present processes, one barrel of Athabasca bitumen will convert to 0.70 to 0.75 barrels of synthetic crude. With *in situ* projects, particularly those employing some form of combustion operations, some upgrading does actually occur in the reservoir so that surface barrels are qualitatively different from reservoir barrels.

The AERCB gives a figure of 38 billion barrels of bitumen recoverable from 74 billion barrels of crude bitumen-in-place; a surface recovery factor *for mining operations of 51 per cent*. The combined surface-recovery and process-recovery factor is 36 per cent, i.e. the proportion of *synthetic crude* recovered per barrel of bitumen-in-place resulting in recoverable oil of some 26 billion barrels from surface mining operations. These figures relate to existing mining and upgrading technology, both of which may achieve greater levels of efficiency as experience accumulates, thus implying higher recovery levels.

Estimating recoverable reserves in the non-mineable areas is a difficult task, given the apparent lack of a thoroughly tested and proven technology. It is possible however to extrapolate from present technical information to obtain order-of-magnitude estimates of recoverable reserves, assuming future economic and institutional conditions are conducive to their recovery.

Technology and economics will dictate the recovery factors to be obtained using *in situ* or possibly subsurface mining techniques. Company predictions for

individual pilot projects range from as low as 20 to as much as 60-per-cent or higher surface recovery of bitumen-in-place. Assuming, somewhat arbitrarily, that about half of the deeper Athabasca-type deposits are amenable to some kind of recovery mechanism would result in average recovery factors ranging from 10 to 30 per cent or some 72 to 200 billion barrels of recoverable raw bitumen.

Since the predominant recovery technology is unknown at this time, and certain processes can be high energy users, it seems prudent to assume that surface process losses and fuel usage could range from the 30 per cent experienced for ongoing mining operations to 50 per cent or more for *in situ* operations. On this basis, therefore, the likely range of recoverable reconstituted or upgraded crude oil could be from 40 to 140 billion barrels from all of the Athabasca-type deposits not considered to be amenable to surface mining operations. These figures are, of course, only very rough estimates at this time and assume significant continued development of technology and improvements in economics. Nonetheless massive production potential, by any yardstick, appears to exist in the Alberta oil-sands deposits.

As discussed in a subsequent section, however, these resources would appear to be either marginal or sub-economic based on today's technology. It seems likely that oil-sands development, both for mining and for *in situ* projects, in the near term will fall far short of the significant volumes required to make substantial inroads on Canada's current oil-supply shortfall. Increases in world oil prices or significant improvements in technology could accelerate such development—but project lead times will remain a problem. Particularly for *in situ* projects, about a 10-year planning, project definition and construction period will be required to bring new projects on stream, even after participants are satisfied with the reliability and efficiency of technology. Even given satisfactory institutional and economic guidelines, therefore, large volume contributions to Canada's energy supply balance from oil-sands sources remain, elusively, a decade or more in the future.

UTILIZATION OF HEAVY OILS

The heavy oils of Lloydminster and Cold Lake and the bitumen found in Athabasca, Peace River, Wabasca and Buffalo Head Hills deposits are all of essentially the same basic chemical and physical nature. They are mixtures of asphaltic hydrocarbons similar to those found in conventional crude oil, but of higher molecular weight and, therefore, heavier and more viscous. Furthermore, they all contain high percentages of sulphur. The Lloydminster oils and to a lesser degree, the Cold Lake oils will flow at normal temperatures, but the oil-sand bitumens are generally solid unless heated.

The most valuable use for these oils has been for asphalt manufacture, for which they are particularly suitable. They were not used extensively to make fuel products, both because of their higher cost of production, and their lower value as an oil-refinery feedstock. Technology has existed for many years to convert them to lighter products, but this technology is relatively expensive and could only be justified if the cost of the feedstock were relatively low. Canada has now reached the stage however, where production of conventional crude oil from the western sedimentary basin has peaked and is expected to decline steadily in the future. At the same time, we have some of the world's largest resources of heavy oils and the economics of their utilization is at a crucial point of change.

Characteristics of the Heavy Oils

The difference in quality between the heavy oils typical of Lloydminster and Cold Lake and a light sweet Alberta crude is illustrated in Table 4. Also shown are the equivalent properties of a "synthetic crude" produced from Athabasca bitumen, and the average properties of crude oils fed to Ontario and Quebec refineries, which supply the largest Canadian markets. Western refineries have generally run light sweet crude as shown in the left-hand column. It is clear that Lloydminster and Cold Lake oils are both very much heavier and higher in sulphur content than average Canadian refinery feeds.

The yields shown in the table refer to three principal fractions:

- *Distillates.* Oil with a boiling point of up to about 650°F; represents light fractions producible by atmospheric distillation.

- *Cracking Stock.* Oil with a boiling point of approximately 650-950°F; distillate obtained by vacuum distillation; too heavy to be included in distillate fuels such as automotive diesel and heating oil; normally catalytically cracked to lighter products; most lubricating oils are also produced from this fraction.

Table 4
COMPARISON OF REFINERY YIELDS FROM HEAVY AND LIGHT CRUDES IN RELATION TO CANADIAN REQUIREMENTS

	Light Sweet Alberta	*Heavy Oils*			*Upgraded or "Synthetic" Crude*	*Typical 1975-76 Refinery Feedstocks*		*Approx. Boiling Range °F*
		Lloydminster	*Cold Lake*	*Athabasca*		*Ontario*	*Quebec*	
Gravity °API	41	16	11	10	39	36	33	
% Sulphur	0.1	3.5	4.7	5.0	0.04	0.5	1.3	
Yields by Distillation (% volume)								
"Distillates": (gasoline, diesel, jet fuel, kerosene, light fuel oil)	68	29	17	15	82	52	51	0-650
"Cracking Stock"*	27	37	37	35	18	34	31	650-950
"Residual" (asphalt, heavy fuel oil)**	5	34	46	50	–	14	18	950+

*About 80 per cent may be converted to distillate fuels by catalytic cracking.
**About 50 per cent may be converted to distillate fuels by coking, or up to 80 per cent in combination with other processes.

- *Residual.* Impurities such as sulphur and metals tend to concentrate in this fraction, making it difficult to convert to lighter products; usually disposed of to heavy fuel oil, with a part being utilized for asphalt production.

It is clear from Table 4 that the quantities of "residual" derived from Lloydminster and Cold Lake oils are greatly in excess of the quantities normally produced by Canadian refineries.

Traditional and Future Markets for Heavy Oils

The term "heavy oil" is imprecise in that the cut-off points between "light", "medium" and "heavy" have never been generally defined and are used loosely, depending often on the context and the geographical origin. In Canada, oils up to 28° API have generally been classified as "heavy" and include those from the Midale-Weyburn, Fosterton-Dollard and Smiley-Coleville fields of Saskatchewan and Bow River in Alberta.

In this document, only the Lloydminster-type oils and heavier are under consideration; that is, oils generally having gravities in the 10-17° API range. Although small volumes of Lloydminster oil have traditionally been included with "conventional" crude oils, the bulk of the Lloydminster oil is more appropriately classed with Cold Lake and the oil sands both technically and economically. The enhanced or tertiary recovery techniques by which the bulk of the Lloydminster oil may be recovered are closely allied to the *in situ* techniques applicable to the oil-sand areas; the upgrading techniques are essentially identical. The costs of producing and upgrading Lloydminster oil may be somewhat lower than oil-sand production but, on the other hand are much higher than the costs associated with "conventional" oils.

The 1976 markets for these heavy oils are indicated in Table 5, representing a total production of a little over 100 000 barrels per day.

Table 5

1976 DISPOSITION OF HEAVY OILS

(thousands of barrels per day)

	Lloydminster	*Cold Lake*	*Athabasca*
Canadian asphalt and fuel products	26	5	—
Export blend	21	—	—
Local upgrading to "Synthetic Crude"	—	—	50
Total	47	5	50

Estimated 1976 Canadian sales of asphalt totalled about 50 000 barrels per day, representing a potential related market for approximately 125 000 barrels per day heavy oil. However, there are several reasons why only part of this

demand may be satisfied by Alberta and Saskatchewan heavy oils. A major reason is that the Montreal refining centre has traditionally been supplied with Venezuelan and Eastern Hemisphere crude oils and some of these crudes are highly suitable for asphalt feedstocks. Montreal refiners hesitate to switch to Canadian heavy oil, only recently available in Montreal, while uncertainties remain as to the origin of future Montreal oil suppliers. Furthermore, other Canadian oils in the medium gravity range are also suitable for asphalt and absorb part of the market.

There is another objection to the expansion of the use of Lloydminster crude oils directly in Canadian refineries. To be transportable by pipeline, 18-per-cent condensate must normally be blended with Lloydminster-type crude oils. This results in a movement of condensate to a market where it may not optimally be used. Prairie markets require relatively high gasoline yields and condensate may readily be converted to gasoline. In the heavily populated regions of Ontario and Quebec, however, middle distillates are in relatively strong demand and there is concern that the gasoline/distillate demand ratio is becoming too low for maximum refinery efficiency—in which case condensate supplies are unwanted. Furthermore, condensate production in Alberta is predicted to fall steadily, and what is available could preferably be allocated to gasoline production and/or petrochemical feedstock.

The United States export market has in the past provided a major outlet for Canadian heavy oils. Refineries have been built in the northern United States specifically to process these heavy oils; some are equipped with coking plants for conversion of the residual to distillates. These oils also satisfy much of the asphalt demand in this area. Because of the importance of these markets to the heavy-oil producers in Canada, the National Energy Board has decided to license the export of heavy crude oils separately from "conventional" oils. It has been recognized that in the near term, these exports must be maintained in order to assure the continued development of the heavy-oil fields. For the longer term, however, this oil is expected to be required for Canada's domestic needs. To meet this objective, a choice must be made between the alternative of modifying existing Canadian refineries, or building upgrading plants that will convert the heavy oil into a "synthetic crude" acceptable to existing refineries.

A strong case can be made for the "upgrading" alternative. First, the heavy oils are difficult to transport until they have been upgraded, so that an upgrading facility close to the source of production has a significant transportation advantage. Second, large quantities of energy are required for the production of the bitumen, whether by mining or *in situ* methods, and it is technically convenient to integrate a utility plant with the upgrading plant, producing steam and electricity as required for the producing, upgrading and transportation operations. Third, it may well prove beneficial to utilize other western energy resources, e.g. coal and/or natural gas, to enhance the production of the more valuable liquid fuels. Finally, the location of these large industrial facilities in the producing areas may well improve the balance of industrial concentration across the country.

Upgrading Economics

It has been pointed out in the foregoing that heavy oil may be upgraded by one of two basic approaches:

- *Coking:* Thermal cracking to lighter products and a carbonaceous residue containing most of the sulphur and metallic contaminants, followed by hydrocracking of the distillate; and

- *Hydrocracking:* Thermal or catalytic cracking under hydrogen pressure.

Both these approaches require the manufacture of hydrogen. Hydrocracking will provide greater liquid yields, but is presently less accepted by the oil industry, being a higher cost, less-proven technique when applied to residuals. The two existing Athabasca mining projects (in operation and building) each use the coking route. However, the costs of each process are close enough that future upgrading plants may use either.

Current estimates indicate that upgrading costs will be in the range of $2 to $4 per barrel, including costs related to the capital investment (of the order of $4 000 to $6 000 per barrel per day of capacity). These costs will depend on the size of the plant, and on the degree of upgrading. An optimum size is generally assumed to be of the order of 100 000 barrels per day, although a plant half this size may prove to be economic. The severity of upgrading may vary, so that the sulphur content of the synthetic crude product may be reduced to less than 0.1 per cent by weight or only partially removed to, say, 2 to 3 per cent. Likewise, the 0–650°F distillate in the synthetic crude may vary from 45 to 65 per cent by volume and the gravity from 20 to 35° API. The extent to which the crude is upgraded will depend principally on the capabilities of the refineries to which the synthetic crude will be supplied. Since Eastern Canada presently has a surplus of refining capacity which should be utilized to accommodate future demand growth, upgrading should most logically be designed to accommodate these existing refineries. In the longer term, it will likely also prove economically attractive to produce some finished products at the upgrading plants for direct supply to contiguous markets. In either case, all production will be of low enough viscosity for economical pipeline transportation.

An important factor in the economic comparison between the two process routes is the production of low-value by-products—coke and heavy residual oil. Most process configurations under study involve the gasification of the bulk of these residues, the gas being scrubbed of sulphur compounds and used for hydrogen production or burned in a utility plant to supply heat and power both to the upgrading plant and to the field production operations. The economics will be favoured by the attainment of a satisfactory heat-and-product balance, requiring neither the import of a subsidiary fuel such as natural gas nor the accumulation of hard-to-dispose-of coke or residual oil. An additional factor that must be considered is the desirability of using a low-value subsidiary fuel

such as lignite, in combination with hydrocracking, to improve the overall yield of high-value liquid products.

It follows from the estimates of upgrading costs, that a corresponding price differential of $2 to $4 per barrel must be attained between the price of raw heavy crude and light crude oils similar in quality to the upgraded crude. This differential, however, does not presently exist.

The Alberta pricing is presently based on a "marker" crude (42° API, 0.4-per-cent-by-weight sulphur) with quality differentials of 3 cents per ° API and 2 cents per 0.1-per-cent sulphur. In addition, there is now a 35-cent-per-barrel differential for Lloydminster-type crude oil. Assuming a Lloydminster crude quality as indicated in Table 4, the differential will be:

	API differential	+	sulphur differential	+	Lloydminster price differential
or	3(42–16)	+	2(3.5–0.4)10	+	35¢
=	78	+	62	+	35
=	$1.75 per barrel				

excluding any transportation differentials.

A heavy oil upgraded to the level of the synthetic crude shown in Table 4 is of higher value than the "marker" crude, and to certain refineries this premium could be of the order of $0.50 per barrel, indicating a total differential of $2.25 per barrel. This compares to upgrading costs of perhaps $3.00 per barrel for this level of upgrading.

It follows that for upgrading to be economic, this differential must increase by at least $0.75 per barrel. Detailed study may show a greater differential will be required when all costs associated with this new industry have been fully evaluated, including transportation differentials.

In the context of present world prices of crude oil and probable price increases in the near future, the overall economics of heavy-oil recovery and upgrading appear favourable. As discussed in the following section, the costs directly associated with recovery and upgrading of Lloydminster-type heavy oils could be below the present cost of Canada's alternate oil supplies, i.e. foreign oil imports. However, the costs are considerably higher than those associated with light crude oils.

ECONOMIC CONSIDERATIONS

In establishing policies for the development of energy resources, three main factors dictate alternatives: the availability of the resource, the availability of technology to recover and prepare these resources for market and their economic viability at foreseen market price levels. The first two factors have already been discussed in some detail.

In considering the economics of oil sands and heavy oils, as with any readily marketable commodity, it is the cost-price relationship that must be scrutinized. The high-cost nature of Canada's future oil and gas supplies along with our increasing dependence upon foreign imported oil has resulted in the adoption of a policy as outlined in *An Energy Strategy for Canada* of "moving towards international oil prices" in Canadian domestic markets. To the extent we are dependent upon foreign and high-cost energy sources, we have little control over domestic energy commodity prices. Increased self-reliance could help free Canada from the whims of the international market in terms of both price and availability of supplies.

There are a number of aspects of the cost of oil sands and heavy oils that must be defined in establishing a common basis for discussion. The total cost of oil production can be broken down into the following components: physical cost, cost of capital, royalty payments and income taxes.

Physical Cost of resources refers to the investment cost plus operating expenses for recovery and production facilities and installations. These are usually expressed in unit-cost terms such as dollars-per-barrel or dollars-per-daily-barrel of production. The capital cost of oil-sands production facilities is often given as \$20 000 to \$25 000 per daily barrel of production capability. Adding operating costs in the range of \$5 to \$7 per barrel brings the total physical cost of oil production to \$8 to \$10 per barrel, including, in this case, upgrading facilities to produce reconstituted or synthetic crude oil. For Lloydminster-type heavy oils, capital costs in the range of \$5 000 to \$8 000 per daily barrel are anticipated for much of this resource, considering only the production or recovery facilities based upon known and extrapolated tertiary recovery technology. When operating costs in the range of \$3 to \$5 per barrel are included, physical unit costs in the \$4 to \$7 per barrel range result. The large volume acceptability of these heavy oils in the Canadian market will require upgrading or partial refining expected to cost \$4 000 to \$6 000 per daily barrel, bringing the unit cost up to the range of \$6 to \$9 per barrel. The physical cost concept excludes a number of important cost components.

Cost of Capital is, of course, a cost of doing business and whether financing is provided from equity or debt sources this business-as-usual concept requires that investment capital be repaid or recovered along with some margin for interest or return of investment. Including capital charges of (say) a nominal 12

per cent with the physical unit costs quoted above would increase oil sands synthetic oil costs to the range of $14 to $16 per barrel. Utility-type financing, whereby governments would bear much of the project risk, would reduce these estimated costs only marginally. Adding capital charges at 12 per cent per annum for the estimates provided above for Lloydminster-type oils would increase their unit cost to the $6- to $10-per-barrel range for heavy raw crude production at the wellhead or to $7 to $11 per barrel for upgraded or reconstituted (mainly light) fuel oils. To reiterate, these costs include investment and operating costs (i.e. physical costs) plus the cost of capital; they do not include royalty or income tax.

Royalties. All of Canada's oil sands and heavy oil resources lie within the provincial boundaries of Alberta and Saskatchewan and therefore fall under provincial jurisdiction and are subject to the payment of provincial royalties. Both provinces produce crude oil volumes greatly in excess of their own needs and therefore cannot be expected to increase oil production for sale to the consuming provinces of Canada without appropriate and equitable remuneration for the selling-off of a non-renewable resource. Provincial royalty payments, however structured, therefore constitute a real component of the cost of oil production in Canada and add to the estimated oil-cost ranges shown above.

Income Tax. Similarly, federal and provincial income taxes represent a cost of doing business, and the payment of a portion of a company's net profit (after recovering expenses) to governments helps to finance, in part, the cost of services provided by governments. In terms of net national benefits, of course, both taxes and royalties represent transfer payments rather than real costs to the nation.

Nonetheless, the reluctance of consumers to pay prices for domestic oil in excess of international price levels imposes a limit upon Canadian oil prices and, by implication, restricts either the marginal physical cost of resources that may become economically viable or restricts the ability of governments to impose fiscal levies, or both. In practice, foreseeable near-term world oil prices may provide little if any margin (in excess of physical cost plus the cost of capital) to levy taxes and royalties upon oil-sands production. Significant development of oil-sands potential may therefore depend upon real and substantive increases in world oil prices.

It would appear, on the basis of the cost estimates shown above, that such is not the case for Lloydminster-type heavy oils. Some volumes may be available at present price levels while a large portion of this diverse resource should become available as Canadian oil prices move closer to international price levels, providing always that tax and royalty take can be kept to reasonable levels. Such decisions, however, are under the control of governments at both levels.

GOVERNMENT INITIATIVES

Intergovernmental cooperation in the form of establishing an appropriate economic environment as well as providing a policy framework that recognizes the unique problems faced by the heavy-oil industry represents the minimum condition within which efficient development — for both production capability and upgrading facilities—can be expected to flourish.

Government initiatives to expedite the development of these resources include the following:

1. The Department of Energy, Mines and Resources has recently concluded an agreement with the Government of Saskatchewan to jointly fund and manage tertiary recovery research projects involving heavy oil reservoirs in the Province of Saskatchewan, the information from which will be available to all interested parties.

2. The Alberta Oil Sands Technology and Research Authority has recently allocated $64 million to five experimental *in situ* oil-sands recovery projects; government funding, generally, is to be matched by the private sector partner in a joint effort to develop or improve recovery methods. Additional funding has been authorized by the Government of Alberta which will bring the total to $144 million under the AOSTRA program.

3. The federal Minister of Energy, Mines and Resources together with Alberta's Minister of Energy have initiated joint federal-provincial discussions at both the technical and policy levels aimed at examining ways and means of accelerating the development for oil sands and heavy oils.

4. The National Energy Board, at the conclusion of its 1976 hearings on the supply and demand for crude oil in Canada, has indicated that heavy crude oils including those of the Lloydminster-type will be licenced separately for export to the United States, at least for an interim period. If producers can be assured of markets in the long term, production capability could be built which would eventually provide the feedstock for an upgrading facility designed to produce energy commodities for the Canadian marketplace.

5. Petro-Canada, the national oil company, in fulfilling its role as the federal government's direct participant in the oil and gas industry is examining the potential and merits of all heavy-oil areas in Canada. Although the examination is in an early stage, Petro-Canada has indicated that emphasis in its review in the near term would include consideration of facilities to reconstitute conventional-type heavy oils so that they could readily be marketed in Canada. Such facilities might be built in stages commencing in the 100 000-barrels-per-day range with an ultimate target for the facilities possibly being as much as 300 000 barrels per day. Hopefully such a project could be onstream by the mid 1980's.

In the absence of major new oil discoveries in our frontier areas the above initiatives constitute an important element in an overall strategy of energy self-reliance. Due to the very long lead times for the development of frontier resources and the technical, environmental and economic difficulties of bringing them onstream it seems likely that frontier oil supplies could not be made available much before 1990, even in the event of large discoveries in the very near future. In view of the assessment that our best remaining geological prospects for the discovery of large oil fields in our frontier areas are almost all exclusively located in offshore areas under permanent or seasonal ice, it may be prudent to assemble alternative energy-supply planning packages. While we shall continue to explore for large oil discoveries in areas like the Beaufort Sea and Labrador Shelf, we must proceed on the basis that such supplies may be beyond the current planning horizon.

Appendix

GLOSSARY OF TERMS

Acre-foot: Unit of volume, one acre in areal extent and one foot thick, or 43 560 cubic feet.

Asphaltic oil: Crude oil containing a significant amount of heavy material suitable for asphalt production.

Bitumen: A naturally occurring viscous mixture, mainly of very heavy hydrocarbons, that may contain sulphur compounds, and that in its naturally occurring viscous state is not recoverable at an economic rate through a well.

Condensate: Hydrocarbon constitutents, generally pentanes and heavier, contained in gas reservoirs that condense and are recovered as liquids during production.

Conventional: Oil recoverable from a well using standard production techniques.

Coke: Refers to petroleum coke, a by-product of petroleum refining, the solid residue remaining after thermal cracking of a petroleum feedstock.

Feedstock: Material that is refined or transformed in a processing operation.

Fireflood: Combustion occurring within a porous hydrocarbon-bearing formation sustained by air injection and designed to increase recovery of the in-place crude oil.

Heavy oil: A high-viscosity, high-gravity crude hydrocarbon.

Hydrocarbon: An organic compound consisting of carbon and hydrogen.

In situ: Means literally “in-place”, usually refers to techniques of separating oil from oil sand in-place or to processes that take place underground or in-place.

Interstitial: Situated within interstices or voids in the reservoir.

Isopach: An equal-thickness contour.

Lens: A body of rock that is thick in the central part, thinning toward the edges.

Mobility: For a reservoir fluid, the ratio of permeability to viscosity under reservoir conditions.

Mobility ratio: The ratio of mobilities between two fluids.

Oil-in-place: The total volume of oil contained in one or more reservoirs, only a portion of which may be recoverable.

Oil sands: Sands and other rock materials that contain crude bitumen and other associated mineral substances.

Oil saturation: Fraction of reservoir void volume occupied by oil.

Outcrop: The exposure of strata projecting through an overlying cover.

Overburden: Material overlying a deposit of useful material.

Pay thickness: The thickness of strata considered to contain petroleum hydrocarbons.

Permeability: Capacity of a porous rock to transmit a fluid under pressure.

Pinchout: The termination or end of a tapering layer of rock.

Porosity: The fraction of void spaces within a rock.

Primary recovery: Petroleum recovery that makes use of only natural reservoir drive mechanisms, i.e. gas cap expansion, solution gas drive or natural water drive.

Real costs: Costs expressed in constant dollars or adjusted to exclude the effects of inflation.

Recovery factor: Fraction of oil-in-place recovered.

Reservoir: A subsurface trap that contains an accumulation of petroleum hydrocarbons.

Secondary recovery: Recovery obtained by any method of augmenting the natural reservoir energy such as by fluid injection.

Sour: Crude oil containing a large mount of sulphur and sulphur compounds.

Synthetic crude: A semi-refined hydrocarbon generally derived from bitumen used as feedstock in a conventional oil refinery.

Tertiary recovery: Generally a third-order or third-generation recovery technique although primary and secondary methods need not necessarily have been previously implemented.

Viscosity: A measure of the ease with which a fluid will flow; fluids with low viscosities flow easily.

Viscous: Processing a high viscosity.

Water of combustion: Water produced as a result of a combustion reaction.

Abbreviations

AERCB: Alberta Energy Resources Conservation Board.

AOSTRA: Alberta Oil Sands Technology and Research Authority.

EMR: Department of Energy, Mines and Resources.

GCOS: Great Canadian Oil Sands Limited.

GSC: Geological Survey of Canada.

NEB: National Energy Board.

Btu: British thermal unit.

B/D: Barrels per day.

Bbbls: Billion barrels.

Bstb: Billion stocktank barrels.

MB/D: Thousand barrels per day.

$/bbl: Dollars per barrel.

°API: American Petroleum Institute method of measuring oil gravity.

Tp: Township.